APPENDIX A

elpaso

Appendix B

Operating Procedure for Enforcement of Gas Quality Specifications for El Paso Natural Gas Pipeline

This operating procedure sets forth herein are for the use of the automated controls necessary to minimize the adverse impact on El Paso Natural Gas Company's mainline system due to the introduction into the system of non-conforming gas.

Section 5.8 of El Paso's FERC Gas tariff, Volume No. 1-A, allows El Paso to reject natural gas, which does not conform to specified quality standards set forth in Section 5.1 of the tariff. El Paso can reject this non-conforming gas after notification to a shipper, until such time as the shipper corrects the deficiency or El Paso is able to make those changes necessary to cause the gas to conform to the requirements of the tariff.

Set points and alarms will be applied to all locations consistent with the gas quality provisions of El Paso's tariff. Gas receipts will be shut-in, if the quality specifications defined in El Paso's tariff are exceeded. Adjustments in these set points and alarms may be necessary at individual location due to recurrent incidents by operations intended to circumvent compliance with tariff requirements or due to unique conditions present at the receipt point.

H_2S - Hydrogen Sulfide

Section 5.8 of El Paso's tariff allows El Paso to reject gas at any mainline Receipt Point that does not conform to the specified quality standards. Therefore, El Paso will not accept gas at any mainline Receipt Point with an H2S content exceeding 0.25 grains per 100scf. For those plants addressed under Section 5.4 of the tariff, El Paso will not accept gas at a concentration over the stated H2S tariff provisions of 0.45 grains per 100scf.

Gas receipts exceeding the referenced H_2S content will be shut-in immediately by manual or automated control. Gas flow will not resume until a reset signal is initiated and/or approval is given by El Paso's Gas Control Center. The reset signal will occur only after an El Paso field technician has verified that the gas quality meets the prescribed standards.

CO_2 - Carbon Dioxide

Section 5.5 of El Paso's tariff allows El Paso to accept natural gas in excess of the stated CO2 content of 2.0%, or the percent addressed in Sections 5.2 and 5.3 of the tariff, until such time as El Paso determines that the natural gas must conform to the tariff to maintain prudent operation of all or part of the mainline system. Upon implementation of these procedures, El Paso will not accept gas-containing CO2 at a concentration over the stated CO2 tariff provisions.

Gas receipts exceeding 2.0% CO2 will trigger an alarm which will alert the El Paso Gas Control Center. If at any time the CO2 content exceeds 2.0%, El Paso's Gas Control Center staff will notify the operator and/or producer that the CO2 level exceeds the standard and that corrective action must be taken.

If at any time, the gas CO2 content exceeds 2.1% for 12 minutes or three analyses whichever is shorter, the receipt valve will be shut-in by manual or automated control.

If a plant operator notifies El Paso of plant start-up problems or other plant problems, El Paso will work with the operator to avoid shut-in. For those plant Receipt Points addressed under Sections 5.2 of the tariff, El Paso shall curtail volumes down to 125% of the historical volumes stated in the tariff provision. Curtailment will be in accordance with Section 5.5 (1), (b), and (c).

In the event that the gas is shut-in due to high CO_2 content, flow will not resume until a reset signal is initiated and/or El Paso's Gas Control Center staff gives approval. The reset signal will occur only after an El Paso field technician has verified that the gas quality meets the prescribed standards.

Total Diluents

Total diluents are the combined amount of Carbon Dioxide, Nitrogen, and Oxygen. Upon implementation of these procedures, El Paso will not accept gas-containing diluents at a concentration over the stated tariff diluents provisions.

Gas receipts exceeding 3.0% diluents will trigger an alarm, which will alert the El Paso Gas Control Center. If at any time the diluents content exceeds 3.1%, but is less than 3.5%, El Paso will contact the operator and work with such operator to establish a schedule for compliance to avoid the gas being shut-in by El Paso.

El Paso's Gas Control Center staff will notify the operator and/or producer that the diluents level exceeds 3% and that corrective action must be taken. If corrective action is not taken the Receipt Point will be shut-in by manual or automated control.

If at any time, the gas diluents content exceeds 3.5% for 12 minutes or three analyses whichever is shorter, the receipt point valve will be shut-in by manual or automated control.

If a plant operator notifies El Paso of plant start-up problems or other plant problems, El Paso will work with the operator to avoid shut-in. For those plants, Receipt Points addressed under Sections 5.2 of the tariff, El Paso shall curtail volumes down to 125% of the historical volumes stated in the tariff provision. Curtailment will be in accordance with Section 5.5 (1), (b), and (c).

In the event that the gas is shut-in due to high diluents content, flow will not resume until a reset signal is initiated and/or El Paso's Gas Control Center staff gives approval. The reset signal will occur only after an El Paso field technician has verified that the gas quality meets the prescribed standards.

Section 5.5 of El Paso's tariff allows El Paso to accept natural gas in excess of the stated diluents content of 3.0%, or the percent addressed in Sections 5.2 and 5.3 of the tariff, until such time as El Paso determines that such natural gas must conform to the tariff to maintain prudent operation of all or part of the mainline system.

BTU – Heating Value

Section 5.10 of El Paso's tariff allows El Paso to reject natural gas at any mainline Receipt Point with a Heating Value of less than 967 BTU per cubic foot.

Gas receipts less than 967 BTU at Mainline Receipt Points will trigger an alarm, which will notify the El Paso Gas Control Center. Upon receiving the alarm, El Paso's Gas Control Center staff will notify the operator and/or producer that the BTU level is less than the standard and that corrective action must be taken.

If the Heating Value is less than 957 BTU, the gas will be allowed to flow for a period for 12 minutes or three analyses whichever is shorter, the receipt point valve will be shut-in by manual or automated control.

Gas flow will not resume until a reset signal is initiated and/or approval is given by El Paso's Gas Control Center. The reset signal will occur only after an El Paso field technician on site has verified that the gas quality meets the prescribed standard.

Hydrocarbon Dew Point

Section 5.8 of El Paso's tariff allows El Paso to reject natural gas at any mainline Receipt Point with a hydrocarbon dew point in excess of 20° Fahrenheit.

Gas receipts exceeding 1065 BTU at Mainline Receipt Points and/or a Hexane mole percentage larger than 0.15% will trigger an alarm, which will notify the El Paso Gas Control Center. Upon receiving the alarm, El Paso's Gas Control Center staff or other authorized personnel will verify the hydrocarbon dew point of the flow stream from an available 10-component gas analysis.

If the hydrocarbon dew point temperature at the deliver pressure exceeds 35° Fahrenheit, the operator and/or producer will be notified that corrective action must be taken. If the hydrocarbon dew point temperature does not decrease, an El Paso technician will be dispatched to verify the hydrocarbon dew point with onsite analytical equipment and when the dew point temperature is confirmed over twenty (20°) Fahrenheit, the receipt point will be shut-in.

Flowing Gas Temperature

Section 5.8 of El Paso's tariff allows El Paso to reject natural gas at any mainline Receipt Point with a flowing gas temperature in excess of 120° Fahrenheit.

Gas receipts exceeding 120° Fahrenheit will trigger an alarm, which will notify the El Paso Gas Control Center. Natural gas with a flowing gas temperature exceeding 121° Fahrenheit, but less than 130° Fahrenheit will be allowed to flow for a period of 60 minutes prior to shut in.

After the initial 60 minute interval or at such time that an El Paso field technician verifies that the delivery of natural gas does have a flowing temperature exceeding 120° Fahrenheit, the facility will be shut-in. If the flowing gas temperature exceeds 130° Fahrenheit, the gas will be shut-in immediately.

El Paso's Gas Control Center staff will notify the operator and/or producer that the flowing gas temperature is exceeding the tariff provisions and corrective action must be taken. Gas flow will not resume until approval is given by El Paso's Gas Control Center and only after an El Paso technician has verified that the gas temperature is at or below tariff limits.

Water Vapor Content

Section 5.8 of El Paso's tariff allows El Paso to reject natural gas at any mainline Receipt Point with water vapor content in excess of 7.0 lbs/MMscf.

Gas receipts exceeding 7.0 lbs/MMscf at Mainline Receipt Points will trigger an alarm, which will notify the El Paso Gas Control Center. Upon receiving the alarm, El Paso's Gas Control Center staff will notify the operator and/or producer that the water vapor content has exceeded the standard and that corrective action must be taken. If the water vapor content exceeds 7.1 lbs/MMscf, but is less than 9.5 lbs/MMscf for a period not to exceed 60 minutes, the gas will be allowed to flow until an El Paso technician is dispatched to verify the water vapor content and shut receipt point in if water content is over 7.1 lbs/MMscf.

At any time the water vapor content exceeds 9.5 lbs/MMscf, the flowing gas volumes will be shut-in immediately.

Gas flow will not resume until a reset signal is initiated and/or approval is given by El Paso's Gas Control Center. The reset signal will occur only after an El Paso field technician on site has verified that the gas quality meets the prescribed standard.

General Considerations

Compliance with the tariff quality specifications will be monitored at mainline Receipt Points on a real-time basis where it is feasible. Additional monitoring and control may be required depending on the impact on the operating system, or where the customer repeatedly fails to comply with tariff provisions. Monitoring will be undertaken at all facilities by spot analysis or by examining the monthly gas analyses used in the settlement system.

Return of Service

Gas flow will not resume after any gas quality tariff excursion until a reset signal is initiated and/or approval is given by El Paso's Gas Control Center. The reset signal will occur only after an El Paso field technician on site has verified that the quality of the gas at the receipt point does meet the prescribed standard.

Requests for Short Term Excursions of Quality Specification

Due to short term operational situations, a short term excursion may be allowed, on a non-discriminatory basis, to allow delivery of gas that does not conform to the standards provided in this operating procedure. El Paso will consider each request for a short-term excursion based on El Paso's ability to accept such gas volume and not adversely affect the integrity of our pipeline.

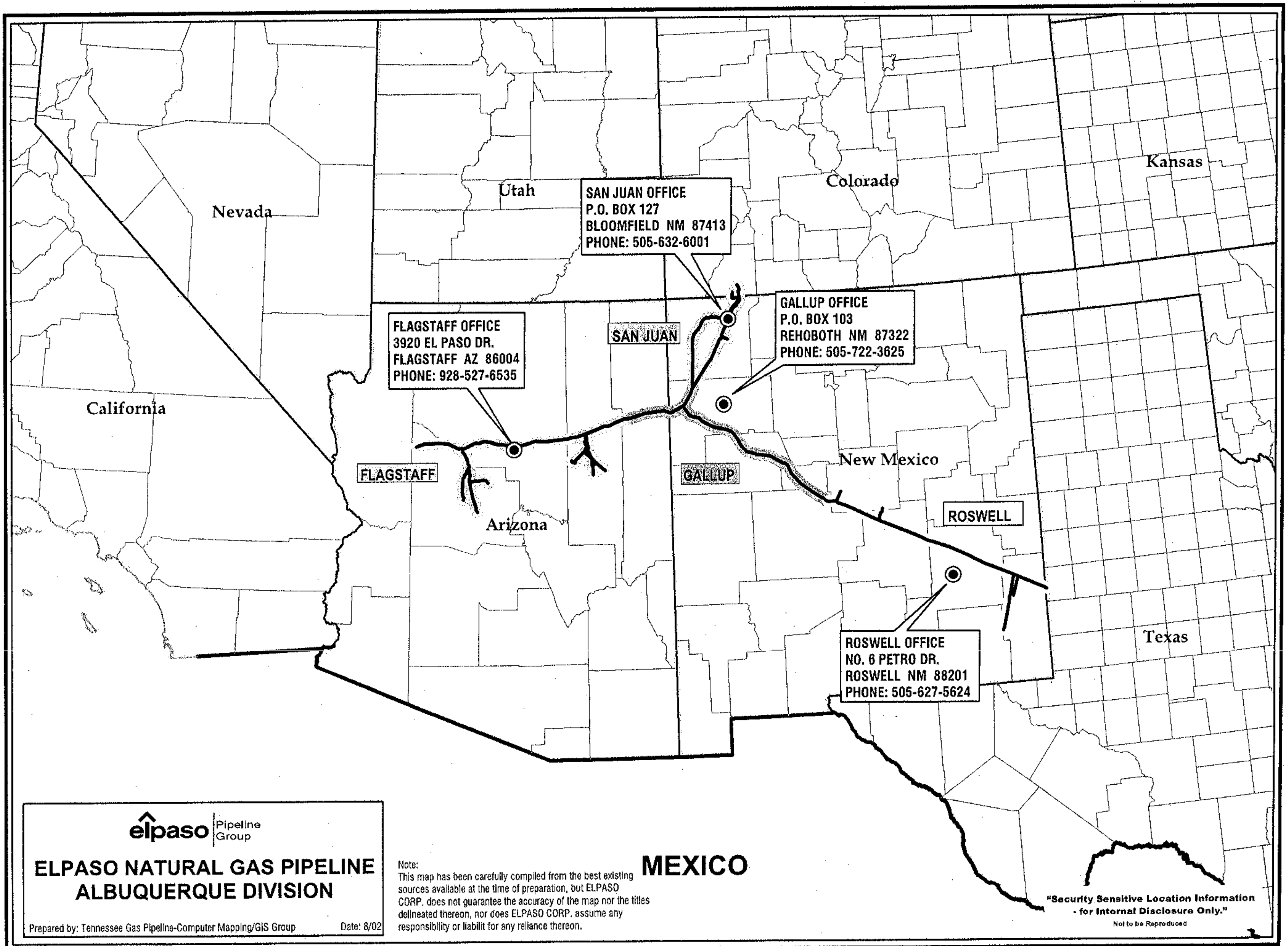
Prior notification of delivery of gas volumes that vary from the quality specifications will be the responsibility of the delivering party. Notification is to be made to El Paso's Gas Control Department prior to delivery of such non-conforming gas volumes. Additionally, contact can be made with the local El Paso Operations Superintendent or Manager.

If the duration of the deliveries will exceed twenty-four (24) hours or will exceed the tariff limits by 150%, notification is required to be in writing. All written requests are to be made a minimum forty-eight (48) hours prior to delivery of the subject volumes.

Written notifications are to be sent to the attention of:

Gas Control Manager
El Paso Natural Gas Company
PO Box 1087
Colorado Springs, Colorado 80944
(719) 667-7711

APPENDIX B


Nevada
Utah
Colorado
Kansas
California
Arizona
New Mexico
Texas
MEXICO
SAN JUAN OFFICE
P.O. BOX 127
BLOOMFIELD NM 87413
PHONE: 505-632-6001
GALLUP OFFICE
P.O. BOX 103
REHOBOTH NM 87322
PHONE: 505-722-3625
FLAGSTAFF OFFICE
3920 EL PASO DR.
FLAGSTAFF AZ 86004
PHONE: 928-527-6535
ROSWELL OFFICE
NO. 6 PETRO DR.
ROSWELL NM 88201
PHONE: 505-627-5624
SAN JUAN
FLAGSTAFF
GALLUP
ROSWELL
elpaso Pipeline Group
ELPASO NATURAL GAS PIPELINE
ALBUQUERQUE DIVISION
Prepared by: Tennessee Gas Pipeline-Computer Mapping/GIS Group
Date: 8/02
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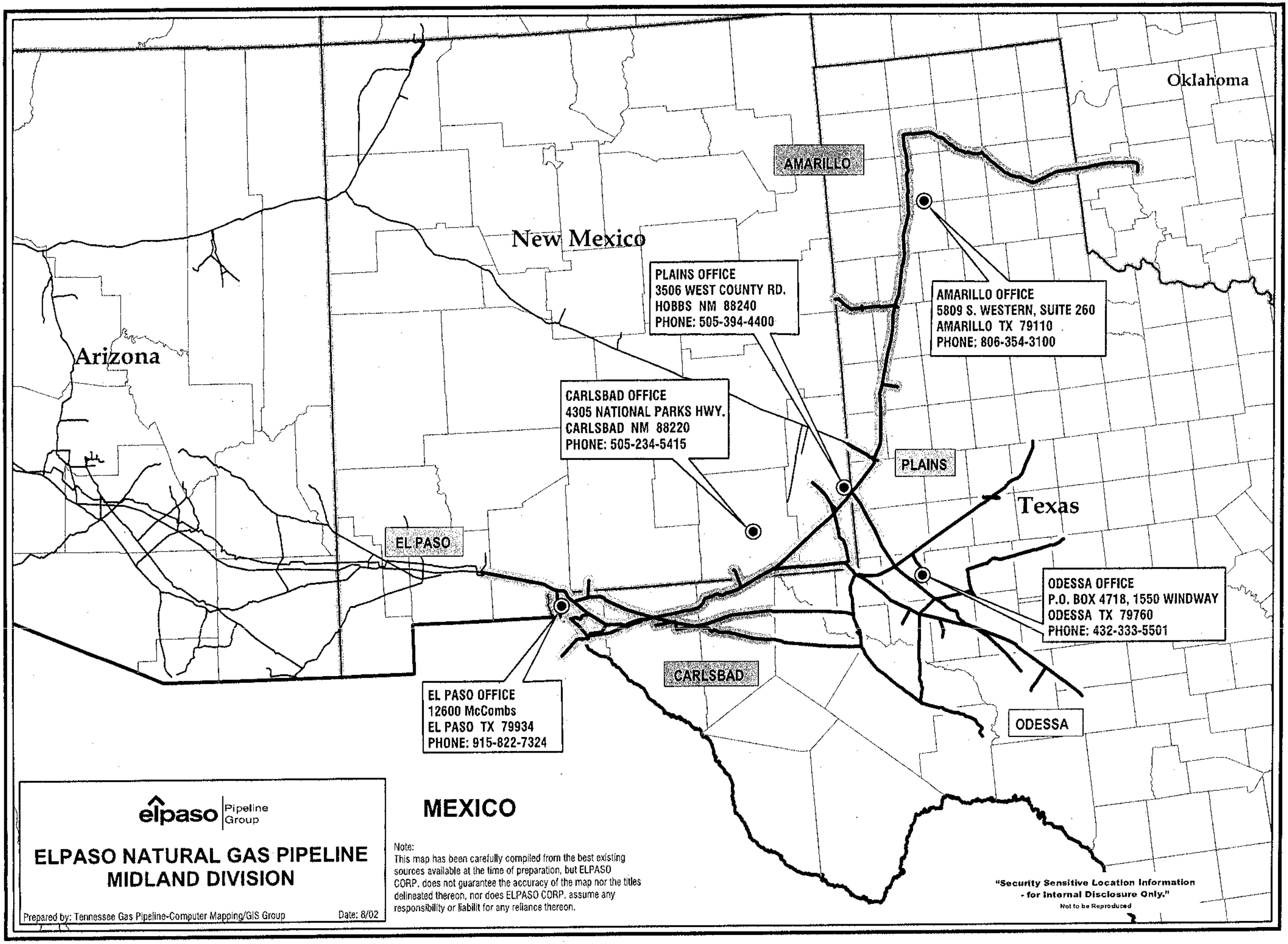

ELPASO NATURAL GAS PIPELINE
MIDLAND DIVISION

Prepared by: Tennessee Gas Pipeline-Computer Mapping/GIS Group   Date: 8/02

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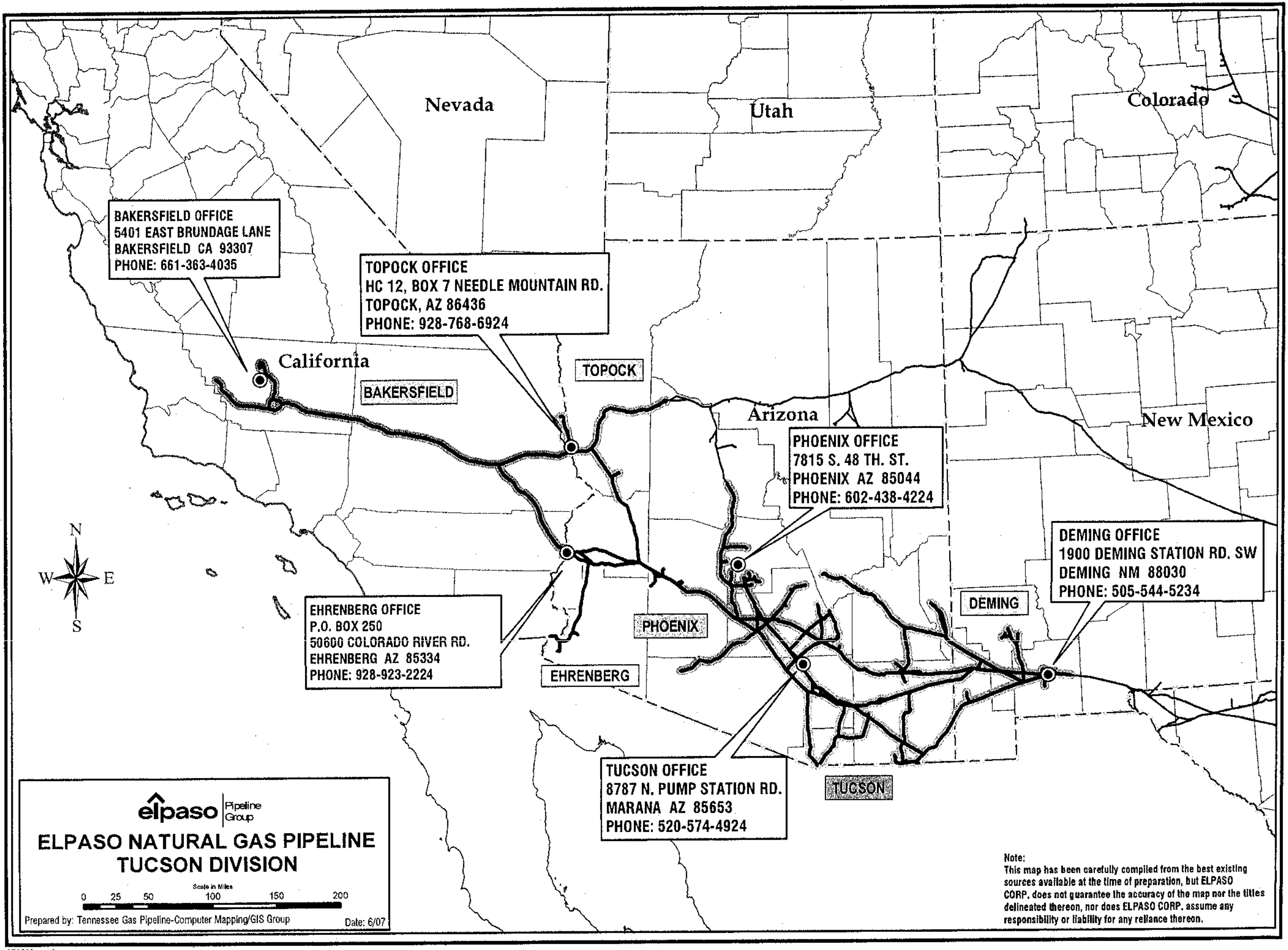

Nevada
Utah
Colorado
California
Arizona
New Mexico
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BAKERSFIELD CA 93307
PHONE: 661-363-4035
TOPOCK OFFICE
HC 12, BOX 7 NEEDLE MOUNTAIN RD.
TOPOCK, AZ 86436
PHONE: 928-768-6924
TOPOCK
BAKERSFIELD
PHOENIX OFFICE
7815 S. 48 TH. ST.
PHOENIX AZ 85044
PHONE: 602-438-4224
DEMING OFFICE
1900 DEMING STATION RD. SW
DEMING NM 88030
PHONE: 505-544-5234
DEMING
EHRENBERG OFFICE
P.O. BOX 250
50600 COLORADO RIVER RD.
EHRENBERG AZ 85334
PHONE: 928-923-2224
PHOENIX
EHRENBERG
TUCSON OFFICE
8787 N. PUMP STATION RD.
MARANA AZ 85653
PHONE: 520-574-4924
TUCSON
N
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elpaso Pipeline Group
ELPASO NATURAL GAS PIPELINE
TUCSON DIVISION
Scale in Miles
0 25 50 100 150 200
Prepared by: Tennessee Gas Pipeline-Computer Mapping/GIS Group
Date: 6/07
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APPENDIX C

Internal Corrosion Site Specific Plans
Annual Review Procedures

Each Area Site Specific Plan will be reviewed annually. The following information will be considered during each annual review.

1. Status of completion of prior year's scheduled activities.
2. Review of all information collected for defined Site Specific Plan segments, which may affect future planned internal corrosion control activities.
    a. Pipeline history
    b. Liquid and sludge sample analysis data
    c. Maintenance pigging reports
    d. Drip blowing reports
    e. NDE findings
    f. Pipeline Inspection Reports
    g. ILI reports
    h. ILI mitigation plans
    i. ILI mitigation plan status
    j. Gas Quality database
3. Review of all recurring planned activities
    a. Maintenance pigging
    b. Pipeline sweeping
    c. NDE inspections
    d. Drip blowing
    e. Gas Quality Reports

The annual review team will analyze the information collected during the previous year to determine if changes to the Area Site Specific Plan are warranted. Specific changes may include.

1. Future inspection schedules
2. Maintenance pigging frequencies
3. NDE inspection locations
4. NDE inspection frequencies
5. Drip blowing frequencies
6. Corrosion monitoring
7. Addition of new facilities
8. Removal or abandonment of facilities

The following represents minimum requirements for adjusting individual Area Site Specific Plan activities.

1. Maintenance Pigging:
    a. Baseline frequencies for maintenance pigging have been established as annually unless different schedules had already been established.

b. Baseline frequencies or established frequencies will be adjusted annually based on the evaluation of information gathered during the prior year. In this context, the term "Internal Corrosion Indicators" will be defined as being evidence of past or current potential internal corrosion activity, and includes, but is not necessarily limited to: NDE evidence of internal wall loss (as defined in Section 305 of the NDE Manual); and/or discovery of the presence of corrosive liquids (as defined in the Liquids Sampling and Analysis which will be inserted into the EP Corrosion Manual, under the heading of "General Procedures").

   i. If no Internal Corrosion Indicators have been present during the prior year the maintenance pigging schedule may be doubled, but not exceed 10 years or the scheduled ILI frequency.
   ii. If Internal Corrosion Indicators have been present during the prior 12 months the maintenance pigging frequency shall be re-evaluated, and shall be not less than ½ of the established maintenance pigging frequency, but not more frequently than quarterly unless operating conditions warrant more frequent maintenance pigging.

c. The specific reason for adjusting any pipeline segment pigging frequency will be documented in the Annual Site Specific Plan Review. A copy of the Annual Site Specific Plan Review shall be maintained by the Area.

2. NDE Frequencies
   a. Keypoint NDE sites will be established in the Area Site Specific Plan to identify specific locations that represent the most likely sites for possible internal corrosion activity. A description of each Keypoint location and the downstream locations being monitored by these Keypoint inspections shall be maintained in the Area Site Specific Plans.

   b. Keypoint NDE inspection frequencies are established based on the information gathered during each inspection.
      i. Initial Keypoint Inspection – No internal corrosion indications discovered.

         1. If no internal corrosion indications are discovered during the initial inspection a re-inspection of the Keypoint location will be scheduled for 10 years

      ii. Initial Keypoint Inspection – Internal Corrosion Indicators discovered.

1. If Internal Corrosion Indicators are discovered during the initial inspection of the Keypoint location **the following will occur:**

a. Undertake a cause and history analysis and perform further NDE inspections at likely points for possible internal corrosion in the segment being monitored by the Keypoint location; **and**

b. An EM coupon or another appropriate monitoring method will be implemented to monitor the Keypoint location for the purpose of determining current corrosion activity; **and**

c. EM coupon or other monitoring results will be used to determine a re-inspection interval based on corrosion growth rate data and remaining life calculations.

iii. Subsequent Keypoint Inspections

1. Re-inspection intervals for Keypoint locations previously inspected shall be determined by recognized industry standards taking into account information gained from prior inspections, EM coupon results or other evaluations.

c. All information used to determine the Keypoint NDE re-inspection frequencies shall be documented in the Area Internal Corrosion Site Specific Plan Annual Review.

APPENDIX D

Section 305 - Internal Corrosion Site Specific Plan Component

1. *General*

This procedure shall assist pipeline operations in the use of nondestructive examination to detect the presence of internal corrosion in pipeline facilities.

The areas for evaluation will be determined by the area manager in accordance with each operating area's internal corrosion site specific plan and per Section 6 of the Corrosion Manual, which recommends typical pipeline locations and components to be inspected. These areas may include, but are not limited to drips, dead legs, end caps, piping and vessels. The inspection areas on horizontal components will concentrate on the bottom, approximately between the 4 & 8 o'clock positions where liquids tend to accumulate

All facets of the inspection including, but not limited to Scope, Terminology, Equipment, Materials, NDE Techniques, Calibrations, References Standards, Definitions and Reporting shall be in compliance with the Company NDE Manual.

This procedure was developed based on the fundamentals outlined in, but not limited to, the Section 200 of the NDE Manual, MES Manual, POP Manual and O & M Manual.

Minimum NDE Inspection Required: Visual Examination (VT), Radiographic Examination (RT) and/or Ultrasonic Examination (UT)

2. *Safety*

Compliance with all safety procedures outlined in the El Paso Safety Handbook is mandatory. Review the POP Manual for the Excavation of Pipeline Flaws Under Pressure. Additionally, hazards associated with coating removal and radiographic operations should be reviewed.

3. *Personnel Qualification*

Personnel meeting the following qualifications shall be used:

1. Company personnel who have successfully completed the PIPEs training class and that are qualified in the following tasks: Radiographic Film Interpretation - 010NDE, Limited Ultrasonic Thickness Measurement – Pipeline 013NDE, Limited Magnetic Particle Inspection – Pipeline 015NDE, and Evaluate Corrosion of Exposed Pipeline Using CORVAL and/or RSTRENG - 019NDE).

> **Note:** All results shall be verified and reviewed by the Company's area NDE Specialist.

or

2. Contract Level II or Level III NDE personnel approved by the Company NDE Superintendent, Operator Qualified through Veriforce for the applicable tasks and must work under the guidance of a Company NDE Specialist.

4. Inspection Procedure

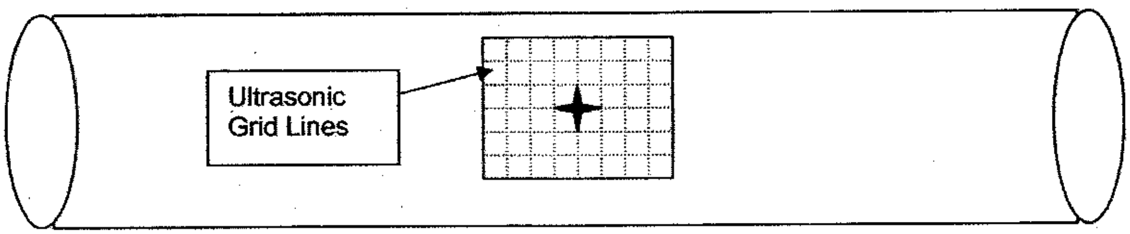
1. UT Inspection – Direct Assessment

Ultrasonic (UT) inspections can be accomplished utilizing various techniques (i.e. A-scan, B-scan, D–meter, etc.). Alternative inspections, such as Teletest and Guided Wave are indirect assessment techniques used for gathering data. All data compiled with indirect assessment shall be verified with direct assessment techniques. This section will outline the basic direct assessment inspection process.

a. The area to be evaluated for internal corrosion shall be identified; certain thick coatings (coal tar) must be removed to facilitate inspection. Other bonded thin coatings (thin film or paint) may not require removal provided satisfactory UT results can be obtained.

b. The area to be inspected as outlined in the component specific section of this guideline, shall have a grid pattern placed over the entire area (bottom 1/3rd of the component) not to exceed 1/2 x 1/2 inch square sections as illustrated in Figure 305-1.

Figure 305-1 UT Inspection Ultrasonic grid lines layout.



c. Calibrate the ultrasonic instrument to the appropriate thickness range and apply suitable couplant over the entire grid area. Depending on the type of UT thickness gauge used, either continuous scanning or individual measurements shall be taken throughout the grid area.

When scanning the area allow for a 10% overlap of the transducer coverage area. Record UT thickness measurements at any grid location that deviates more than 0.010 in. from the average actual wall thickness reading around the indication. If an anomaly is located, evaluate and measure the dimensions of metal loss with the UT instrument.

d. When taking individual thickness measurements, record UT thickness measurements at any grid location that deviates more than 0.010 in. from the average actual wall thickness measurements around the indication. If an anomaly is located, evaluate and measure dimensions of metal loss with the UT instrument.

e. Categorize and evaluate any discontinuities found during the inspection according to the rejection criteria in section 6 of this procedure

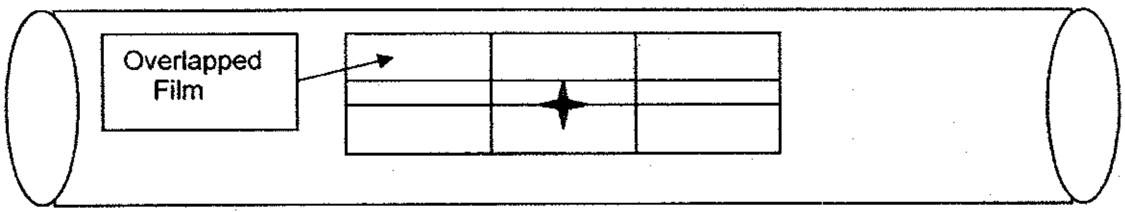
f. Indications recorded may require further evaluation using other NDE methods and assessed to determine the actual cause of the wall loss. This may be accomplished by employing standard RT, advanced UT and/or advanced RT to distinguish between internal wall loss and mid-wall anomalies as per requirements outlined in El Paso's proposed Recommended Guidelines - Welding on Pipe With Internal Discontinuities. (see NDE Manual - Section 308)

2. Radiographic Inspection

Radiographic (RT) examination, using either X-ray or gamma ray as a source, in accordance with procedures Section 201 or 203 in the Company's NDE manual will provide general pipe condition information. However, any indications found shall be evaluated in accordance with the requirements of paragraph 4.1 (Ultrasonic Inspection) of this procedure.

An appropriate size radiographic film shall be placed in direct contact with the component to be examined. It is recommended for large diameter pipe or vessels, that larger than standard pieces of radiographic film be used (e.g. 14"x17" or 8"x10"). If film larger than standard pipeline size film is needed, advance notice to the radiographic contractor is required.

Figure 305-2 Example of radiographic film placement and overlap



A recommended minimum of length 30 inches along the longitudinal axis and from 4 to 8 o'clock circumferentially around the component item should be radiographed.

The area selected to be inspected should have a minimum clearance of 6 inches around the component item to be examined.

Coatings do not need to be removed provided they do not affect the quality of the radiographs obtained.

Only radiographic personnel that are qualified by the Company's NDE Services Group shall be utilized and they will not be required to complete the Company's Radiographer's Qualification Report for this specific type of work. However, they will be required to demonstrate on a test shot that the appropriate IQI sensitivity is clearly visible for the wall thickness of the component item to be examined and that the film densities obtained are between 1.8 and 3.8.

If girth welds or longitudinal seams are involved in the inspection and there are weld quality issues relating to acceptability requirements in API Standard 1104 and API Standard 5L, respectively; contact Laboratory Services or a Company NDE Specialist for consultation.

a. The area to be inspected must have appropriate identification and location markers to permit the area of interest on a radiograph to be accurately traceable to its location on the component item being examined.

b. The source of radiation shall be placed on the component item's surface diametrically opposite the center of the radiographic film that is attached to the component item to be examined.

c. The appropriate IQI shall be used, relative to the nominal single wall thickness in the area of interest. The IQI shall be placed diametrically opposite the source of radiation where the radiographic film is to be attached.

d. The minimum area of the component item that must be inspected is covered in the component specific section of this guideline. Refer to illustration in Figure 305-2 for examples of film placement.

e. The presence of liquids and/or sludge in the component being radiographed may interfere with the quality of the radiographic image obtained. If no density or very light image density appears on the radiographic film, this may indicate the presence of an excessive amount of liquids and/or sludge. This issue shall be so noted on the pipe inspection report and Corrosion Services shall be notified of this condition so that appropriate actions can be taken on the Internal Corrosion Component Specific plans.

f. Interpret the processed radiograph looking for darkened areas which may indicate corrosion or loss of wall thickness. Any areas on the radiograph that appear dark compared to the general average film density shall be inspected in accordance with paragraph 4.1 of this procedure.

3. Combined Inspection Method (Ultrasonic & Radiographic)

If indications or wall loss is detected using paragraph 4.1 (Ultrasonic Inspection), further information may be obtained, but is not required, using paragraph 4.2 (Radiographic Inspection) of this procedure.

If indications or wall loss is detected using paragraph 4.2 (Radiographic Inspection), paragraph 4.1 (Ultrasonic Inspection) shall be used to evaluate the specific area(s).

   a. Remove approximately 12 inches of coating on all sides of the suspected area found during radiographic inspection to facilitate ultrasonic inspection.

   b. Next, follow instructions described in paragraph 4.1 (Ultrasonic Inspection).

5. Component Specific Techniques

1. Component Specific Techniques

The Area Manager will identify inspection locations in accordance with the Area's Internal Corrosion Site Specific Plan.

   a. Piping

      i. Concentrate on the inspection in areas that are most likely to accumulate liquids (the lowest position, sump, etc).

      ii. If necessary remove coating from the bottom third of the pipe (approximately 4 to 8 o'clock). See sections covering coating removal requirements for UT and RT inspections.

      iii. Locate appropriate inspection form for use on pipe.

      iv. If practical, prior to inspection sweep or pig pipeline to remove any liquids.

      v. Inspect for the presence of internal metal loss using the procedures outlined in Section 4 of this procedure.

   b. Drips

      i. If possible, remove all liquids from the drip and take samples of the liquids for analysis.

      ii. Locate the appropriate inspection form for use on drips.

      iii. When performing RT, follow the requirements specified in paragraphs 4.2 (Radiographic Inspection) of this procedure, and as specifically described in the following sections.

      iv. Initially, do not remove any coating to inspect with RT.

v. First utilize RT to randomly spot check the most likely areas to accumulate liquids (the lowest position, sump, etc.); and for corrosion to occur, such as: 1) if liquids removed are primarily compressor oil, then the most likely location for finding corrosion will be bottom center; or 2) if liquids removed have significant percentage of aqueous phase, then target the aqueous/non-aqueous interface.

The RT spot checks should be taken at random locations along the axis of the drip, and accomplished by taking multiple radiographic exposures around the circumference of the drip to ensure that a continuous 360 degree area has been examined for signs of a liquid interface or areas of corrosion.

Additionally, if RT detects the presence of solids, then additional random radiographic exposures should be taken and configured in such a way that the film image can aid in the detection of potential wall loss below the solid interface (i.e. perpendicular to the solids/pipe interface).

Note: During RT, if liquids or heavy solids are directly under the area being examined, it may attenuate the amount of radiation reaching the film and thus affect the film density being seen (e.g. contains heavy liquids/solids - film density will appear lighter; contains little or no liquids/solids - film density will appear darker).

vi. Should and liquid interfaces or discontinuities be located with RT, or if RT could not be used due to heavy concentrations of liquids/solids, then a more detailed characterization using paragraph 4.1 (Ultrasonic Inspection) shall be initiated.

vii. When performing UT, follow the requirements specified in paragraph 4.1 (Ultrasonic Inspection) of this procedure, and as specifically described in the following sections.

viii. Only remove coating in the area to be inspected with UT.

ix. Using any positive results obtained during RT, perform a detailed UT inspection at any identified liquid interface(s) and/or areas of corrosion.

x. If the liquids were not removed and RT was unsuccessful in locating a liquid interface or any areas of wall loss UT spot checks should be taken at random locations along the axis of the drip, and around the circumference of the drip to ensure that a continuous 360 degrees area has been examined for signs of a liquid interface or areas of corrosion.

xi. As an alternate option, special UT techniques performed by NDT Level II or III personnel may be employed to help aid in detection of the liquid interface.

Special UT techniques:

1. Remove a narrow band of coating on one side of the drip from top to bottom.
2. Utilizing a conventional UT flaw detector, calibrate the instrument to the appropriate thickness range for examination of the drip. Adjust the backwall signal reflection on the instrument's screen to 100% full screen height.
3. Apply suitable couplant to drip.
4. Beginning at the top of drip, perform a UT scan from top to bottom.

> **Note:** Areas of the drip where there are no liquids present the backwall signal refection should stay at 100% of full screen height. When a liquid interface is encountered, the backwall signal reflection should reduce to approximately 80% to 90% of full screen height.

5. Mark any areas of the drip where the backwall signal reflection changes. Any liquid interface within the drip should be denoted as a linear line along the relative axis of the drip.

xii. If no wall loss can be identified with either RT or UT then assume this drip is free of corrosion

c. Weld caps

i. Concentrate on the inspection in areas that are most likely to accumulate liquids (the lowest position, sump, etc).

ii. The inspection area should extend from approximately 12 inches of pipe through the girth weld and into the weld cap.

iii. If necessary, remove coating from the bottom third of the fitting (approximately 4 to 8 o'clock).

iv. Locate appropriate inspection form for use on Weld Caps.

v. If practical, prior to inspection remove any liquids.

vi. Follow procedure outlined in paragraph 4.1 (Ultrasonic Inspection) to inspect the area of interest. If more information is requested use paragraph 4.2 (Radiographic Inspection)

d. Blind Flanged Ends

i. Concentrate on the inspection in areas that are most likely to accumulate liquids (the lowest position, sump, etc).

ii. The inspection area should extend from approximately 12 inches of pipe through the girth weld at the weld neck flange. NDE techniques are not reliable for inspecting areas in the weld neck flange; however, ultrasonic inspection through the blind flange just above the bolt holes near the bottom may reveal wall loss on the internal surface of the blind flange.

iii. If necessary, remove coating from the bottom third of the fitting (approximately 4 to 8 o'clock).

iv. Locate appropriate form for use on blind flanged ends.

v. If practical, prior to inspection remove any liquids.

vi. Follow procedure outlined in paragraph 4.1 (Ultrasonic Inspection) to inspect the area of interest. If more information is requested use paragraph 4.2 (Radiographic Inspection).

e. Vessels (scrubbers, filters, volume bottles, etc.)

Note: Whenever possible, visible inspection of the internal wall of the vessel is recommended over NDE external methods. Additionally, the inspection process must be in accordance with the Corporate Pressure Vessel Inspection Manual, which outlines standards for pressure vessel inspections.

i. Concentrate on the inspection in areas that are most likely to accumulate liquids (the lowest position, sump, etc).

ii. If necessary remove coating from the bottom third of the Vessel (approximately 4 to 8 o'clock).

iii. Locate appropriate form for use on vessel inspections.

iv. If practical, prior to inspection drain any liquids from vessel.

v. Follow any of the inspection techniques outlined in Section 4 of this procedure.

vi. Refer to the Corporate Pressure Vessel Inspection Manual for additional information.

f. Elbows

> **Note:** Insulated elbows may be radiographed for metal loss data. However, any suspect indications will need further evaluation, which will require removing insulation and/or protective wrap.

i. Concentrate on the inspection in areas that are most likely to accumulate liquids (the lowest position, sump, etc).

ii. If necessary remove coating from the lowest third of the elbow (approximately 4 to 8 o'clock).

iii. Locate appropriate form for use on elbow inspections.

iv. If practical, prior to inspection sweep or pig pipeline to remove any liquids.

v. Follow any of the inspection techniques outlined in Section 4 of this procedure.

6. Rejection Criteria

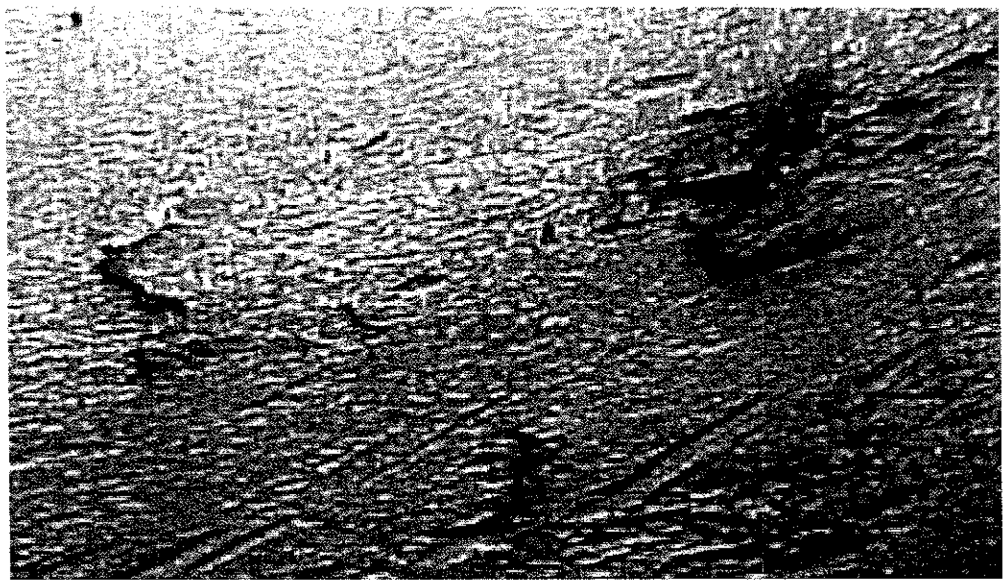
1. Pipe:

1. Mechanical and Inherent Manufacturing Discontinuities

Mechanical and inherent manufacturing (i.e., scab, sliver, spalling, etc.) discontinuities open to the internal surface of the pipe shall be evaluated in accordance with Company established acceptance criteria, which states that any discontinuity with wall loss less than or equal to 10% of the calculated required minimum wall thickness (RMWT) does not impair the serviceability of the pipeline. Discontinuities with wall loss greater than 10% must be evaluated further, repaired or replaced. If the discontinuity is physically accessible for further evaluation the Company's PIPEVAL program may be used.

> **Note:** Mechanical and inherent manufacturing discontinuities may be repaired utilizing either a Type A or Type B weld repair sleeve, composite sleeve, via grinding or be replaced. However, all repairs shall be performed in accordance with established Company practices (i.e., PIPEVAL, etc.).

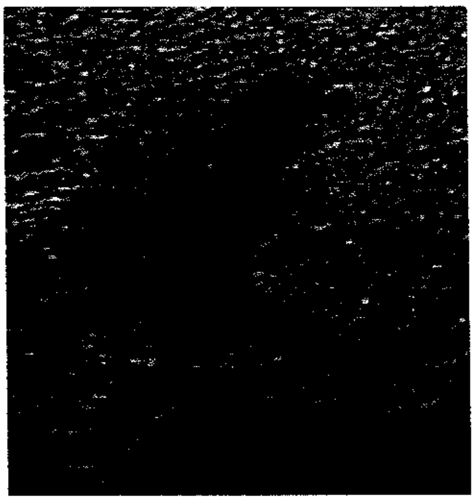
Figure 305-3 Laminations & slivers open to the internal surface



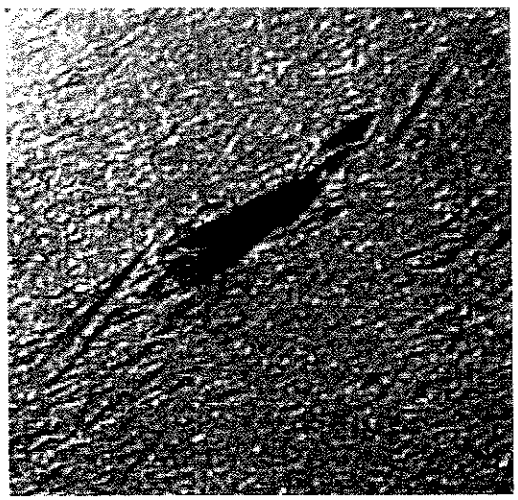
2. Mechanical Inclusions

Mechanical inclusions (mid wall) that are not open to either surface are considered discontinuities and do not impair serviceability of the pipeline.

Figure 305-4 Scabs or laminations that have fallen off/out of the internal surface resulting in wall loss. Differentiating this type of wall loss from internal corrosion is extremely difficult.



Laminations/Slivers



Scabs (with debris missing)

3. Internal Corrosion

   Internal corrosion shall be measured for length, depth and width using any or a combination of the following: UT, RT and MFL data. The gathered data shall be evaluated through COREVAL and based on the results either left in service or repaired/replaced.

Note: Internal Corrosion should be repaired with a Type B weld sleeve or replaced.

2 Fittings

1. For fittings in a pipe system that have the same yield strength (grade) as the pipe in the system and provided that the fitting and pipe Grade is a minimum of X42 and the outside diameter (OD) is a minimum of 16 inches, the following applies:

Note: PIPEVAL (COREVAL) does not apply to fittings.

   a. The depth of continuous uniform wall loss on the fitting cannot exceed the required minimum wall thickness (RMWT) which is defined as 0.010 in. below the nominal wall thickness of the matching pipe.

   b. The depth of non-continuous or isolated wall thickness reductions cannot reduce the fitting wall thickness to less than 93.5% of the nominal wall thickness of the matching pipe or cannot exceed a depth of 6.5% of the nominal wall thickness of the matching pipe.

2. For fittings Grade X-42 and higher in sizes less than 16 inches O.D., as well as all sizes of Grade B fittings the depth of the wall thickness reduction cannot reduce the fitting wall thickness to less than 87.5% of the nominal wall thickness of the matching pipe or cannot exceed a depth of 12.5% of the nominal wall thickness of the matching pipe.

3. For fittings in a pipe system that do not meet the requirements paragraph 6.2.1 or 6.2.2 above further engineering evaluation by El Paso's Laboratory Services is required on a case-by-case basis.

3. Vessels

1. Pressure vessels will be evaluated in accordance with the Corporate Pressure Vessel Inspection Manual and atmospheric storage tanks will be evaluated in accordance with API 653.

Note: PIPEVAL (COREVAL) does not apply to vessels.

7. Report of Examination

The area NDE Specialist shall review all data, including 3rd party reports, and make a final disposition of the particular component inspected, and report all results as follows:

Complete all applicable reports such as: Pipe Inspection Report, Pipe Condition Report, NDE report (NDEX), and Component Specific Inspection reports (e.g. Internal Pipe Inspection, Internal Elbow Inspection, Internal Weld Cap Inspection, Internal Vessel Inspection, Internal Blind Flange Inspection, etc.)

Verbally communicate inspection results with Area Management and Pipeline Services as warranted.

8. Technical Assistance

If technical assistance is required concerning this procedure or if further evaluation of detected or suspected indications found are needed, contact the area NDE Specialist. The NDE Specialist's can be found on the NDE website located at http://epregsharepoint/sites/pipeline/ndeservices/default.aspx or contact the appropriate Superintendent of NDE.

If questions arise regarding the requirements of the Internal Corrosion Site Specific Plans, contact the location's Area Manager or the appropriate Corrosion Services support for that area.

APPENDIX E

Liquid Sampling and Analysis Procedure

§ 1 Liquids

Aqueous and/or hydrocarbon (organic) liquids may be present in natural gas pipelines and facilities, and they are common in production facilities (i.e., gathering lines) and storage field facilities. Since corrosion requires an electrolyte, the absence of liquid water indicates the absence of corrosion. Liquid composition information is useful to estimate corrosivity, but data from monitoring devices such as corrosion coupons or electronic probes are generally considered more reliable (if located properly) since they are a more direct measurement. Liquid measurements can be used to predict changes in corrosivity (or corrosion mechanism) arising from changes in process conditions (e.g., flow rate, temperature, pressure, hydrocarbon fraction, etc.). In addition, the liquid composition can be used to guide selection of treatment chemicals and augment corrosion monitoring through identification of corrosion products.

Corrosion testing is normally performed on the aqueous (water) phase of a liquid sample. Since aqueous liquid samples change with time in a sample container, on-site analysis should be performed without delay. Samples to be held more than 4 hours should be refrigerated (approximately 4°C or 39°F). Samples held for longer than 48 hours, even under refrigeration, are of questionable value with respect to the accuracy of on-site tests.

At least 8 ounces (approximately 250 mL) of water is preferred for complete testing. Smaller samples may be used for performing specific tests. Cleanliness and maintaining an "air free" sample are desired for collecting and transporting samples. Sample bottles must meet the requirements of Appendix F: Sample Containers, Labeling and Shipping. Sample transfers should be performed with minimal agitation or splashing so as not to aerate the sample.

Record all test results on the appropriate form or database and send to Pipeline Services.

A. Sampling Locations

Since liquids are often distributed non-uniformly along a pipeline, sampling locations should be carefully chosen so that it can be collected, represents the majority of liquids within a system, and/or represents the location where corrosion is expected to be most aggressive. Contact Pipeline Services for recommendations on sample points if necessary. Sampling locations may include:

1. Pig Launchers/Receivers
2. Drips (Pipeline, Meter Station, Compressor Station, etc.)
3. Dead Ends (Isolated sections of pipe with no flow)

4. Vessel/Header Drain Lines

5. Tanks

6. Liquid Recovery Vessels (Slug Catchers, Separators, Scrubbers)

7. Meter Tubes

8. Side streams and sample loops

9. Low areas (Sags, River Crossings, etc.)

B. Sampling Methods

Samples may be taken from either flowing (e.g., pipeline) or static (e.g., storage tank) systems. Usually, samples should be obtained by cracking a valve and allowing the fluids to flow for several seconds to flush the valve and associated piping of any foreign matter and/or dead-space fluids before collecting the sample. In some instances (such as with tank bottoms or when sampling from open waters), a specially designed sampling apparatus is required.

Sample pots may be added to each sample valve as needed to provide samples of at least 4-ounces. Sample pots and accessories should be constructed of either a corrosion-resistant alloy or holiday-free, internally coated carbon steel. A double valve arrangement is recommended with one valve on top and one on the bottom of the pot. When liquids are collected, the upper valve should be completely open then the bottom valve slowly opened to collect the sample in a safe manner. The upper valve can be used to isolate the sample pot from the line, especially if the bottom valve fails. If sufficient water volumes are typically present at a sample location, allow the valve to flush with water for several seconds before filling sample containers.

To collect a sample, unscrew the cap on a sample container and completely fill it so any air in the container is flushed out. Immediately recap container. Avoid touching the inside surfaces of the container or cap as this may contaminate the sample. If sufficient sample volume for two sample containers is available, keep one container sealed for lab analyses, and use the other bottle for field tests. However, if the volume of liquid is limited, it may not be possible to fill an entire 250-mL bottle. Obtain as much sample as possible in this container and perform the field measurements with the minimum volume necessary.

If samples are primarily water, even if they contain some solids, prepare and label the sample bottles (before sampling), record the sample pot volume for comparison with the amount of liquid sampled. An 8 ounce (250 mL) size sample is recommended. If additional liquid volume is available, fill two bottles.

When an oil-water emulsion is obtained, collect two samples. After each sample volume is collected put the cap on the container but do not tighten – gas breakout could pressurize the bottle. From one container, perform one of the following procedures to obtain a 2-ounce (approximately 60 mL) water sample:

1. Allow the phases to separate by gravity within prescribed time frames designated by the individual test procedures.

2. Add "knock out" drops to the sample, shake sample 20 times, relieving the pressure and let stand for 30 minutes.

3. Centrifuge the sample to separate out the required amount of water within prescribed time frames designated by the individual test procedures.

If the separation procedure exceeds the allotted time for the test procedure to be conducted, discard the sample. If at least 2 ounces of water is collected, perform on-site testing. In addition perform bacteria culture testing, if required or recommended. If water does not separate and bacteria testing is still desired, refer to the microscopic analysis procedures. Send the second emulsion sample to an approved lab for analysis.

If monitoring bacteria in the liquid sample is required, remove the necessary volume to perform these tests immediately to minimize exposure to oxygen, and before performing any physical or chemical tests (to minimize contamination).

All relevant safety precautions shall be used when collecting liquid samples. Most pipeline facilities are operated at high pressure so extreme care should be exercised by personnel collecting samples from in-service equipment. Always identify all safety concerns and precautions to be taken in the event that a valve used for sampling malfunctions or a high-pressure surge through the sample valve blows the sample container and contents out of the sampler's hand. Follow safety requirements as prescribed in the El Paso Safety and Health Handbook. Additional safety apparel shall be worn if a specific chemical's Material Safety Data Sheets (MSDS) suggest the need for such apparel.

C. Sample Analysis

If possible, water samples should have enough volume to perform both on-site and laboratory analyses; ideally, fill two 250-mL (8-oz.) bottles with sample (one bottle for on-site tests and the other for laboratory analyses). An aliquot of the sample also needs to be acidified by injecting 20 to 40 mL of the aqueous sample with a syringe into a 40 mL vial containing nitric acid (HNO_3). When sufficient water is available, an even larger sample volume is preferred. If a large volume of water is available, a third sample bottle (250-mL or larger) can be acidified by adding HNO_3 to the sample until the pH is < 2.

D. Field Tests

On-site measurements or field tests for aqueous liquid samples include: *liquid temperature*; *pH*; *total alkalinity* [bicarbonate (HCO_3^-), carbonate ($CO_3^=$)] and hydroxide (OH^-) alkalinity]; *dissolved H_2S*; and if required or recommended, *bacteria*. The procedures are summarized here, and *Appendix A* contains detailed procedures for performing on-site physical and chemical measurements and *Appendix B* contains the procedures for microbiological testing.

1. *Temperature* of the liquid is can be measured using a thermometer or electronic meter and is tested in the field because it will change with time.

2. *pH* of liquid water is measured by a pH meter or pH paper in the field as soon as possible after sample collection because the pH is expected to change following depressurization. This is primarily due to dissolved gases leaving the sample. In some cases, when water samples containing significant levels of dissolved iron are exposed to air, oxidation/hydration of the iron can cause pH levels to drastically drop over time.

3. *Total alkalinity* is a pH-dependent parameter; therefore, when the pH changes, total alkalinity concentrations also are affected. The total alkalinity test is a titration method where a measured amount of water is placed in a test tube or bottle with a pH indicator (e.g., bromcresol green). An acidic reagent (dilute H_2S04) is added until the color changes from green to red to indicate that the pH is less than 4.5. The number of drops used to change the liquid sample to red corresponds to the representative concentration of calcium carbonate in the sample and is used in a calculation to find total alkalinity in mg/L. If the pH indicator turns the liquid sample red before the addition of any reagent, the pH of the liquid sample taken from the pipeline was 4.5 or less and no bicarbonate can be present. Note that if a water sample's pH is less than 4.5, there is no need to perform the total alkalinity field test since it can be assumed to be zero.

4. *Dissolved H_2S* tests are done in the field because it will leave the sample following depressurization (and be absorbed into its container during transportation). Several field tests are available for measuring H_2S, and a common one involves using an Alka-Seltzer^R tablet to liberate the dissolved H_2S from a measured amount of an aqueous sample in the form of H_2S gas. A piece of lead acetate test paper is placed over the top of the testing bottle, and the liberated H_2S gas reacts with the lead acetate to form a brown color on the test paper. Using a color chart, the shade of the brown color is compared to the appropriate concentration (in ppm) of dissolved H_2S. Other tests are available that require less sample volume.

It should be noted that black or deeply colored water samples might be difficult to interpret using this method.

5. Levels of viable *bacteria* may increase or decrease in a few hours time due to the effects of oxygen and other factors. For example, some facultative microorganisms' growth and numbers may be stimulated by exposure to air while other stricter anaerobes may be injured or killed by oxygen. When required (i.e., when EM coupon monitoring is not performed), liquid samples are typically tested in the field for levels of planktonic bacteria by inoculating liquid media culture vials using serial dilutions. Liquid cultures identify broad groups of viable microorganisms (APB, SRB, facultative anaerobes, etc.) present in liquids on a semi-quantitative (as a range of organisms vs. a specific number) basis. Liquid samples may also be preserved in the field by "fixing" them in a formalin-based solution in order that microscopic analysis and microbial enumeration can be performed. It should be noted that such analysis will quantify all bacteria present in that liquid sample whether the organisms were dead or alive when the sample was collected. Other microbiological tests also are available for field enumeration of bacteria in liquid samples, which are generally more specific in nature (e.g., RapidChek^R for SRB).

E. Laboratory Tests

A typical liquid compositional analysis generally consists of five components: *metal/cation analysis*, *anion analysis*, *glycol scan*, *alkalinity* and *miscellaneous tests* such as pH, specific gravity, total dissolved solids, conductivity, and corrosion inhibitor residual.

Most results from liquid analyses are expressed in parts per million (ppm). 'Parts' refers to the amount of analyte (i.e., dissolved solids) dissolved in each million parts of solution (e.g., water). This concentration, C, is calculated by:

$$C_{ppm} = \frac{\text{weight solute (mg)}}{\text{weight solution (mg)}} \times 10^6 \text{ ppm}$$

Water collected from pipelines is often dilute and therefore have a specific gravity of approximately 1.0 g/mL so that 1kg of water is approximately 1L:

$$C_{ppm} = \frac{\text{weight solute (mg)}}{\text{volume solution (L)}}$$

1. A <u>metal/cation analysis</u> reports the concentration (ppm) of common cations (positively charged ions). The species and concentrations of ions can be used to predict formation of deposits or, together with other information, indicate corrosion.

2. An anion analysis reports the concentration (ppm) of common anions (negatively charged ions). The species and concentrations of ions can be used to predict acceleration of corrosion or pit initiation (e.g., chlorides), or inhibition of corrosion (e.g., phosphates). Condensed water typically has a low concentration of chlorides, and produced water typically has high chloride.

3. A glycol scan is used to detect the total amount (%) of alcohol type compounds contained within a liquid sample. These compounds include methanol, isopropanol, diethylene glycol, ethylene glycol, propylene glycol, and triethylene glycol. Methanol may be introduced to a wet system as carrier for treatment chemicals. Glycols may be introduced to a dry system as a non-volatile carrier of treatment chemicals. However, the presence of glycol may also indicate upsets or carryover from gas dehydration, which may introduce water, chlorides and other corrosive contaminants to the system. It should also be noted that under certain conditions, glycol may be broken down into organic acids.

4. Alkalinity is determined by bicarbonate, carbonate, and hydroxide ions. These are common constituents of waters that have the ability to neutralize acids and may act as pH buffers. Bicarbonate and carbonate ions together with suitable cation (e.g., calcium, iron) forms commonly found scales. In general, as alkalinity increases, corrosivity tends to decrease.

5. Miscellaneous tests include inhibitor levels, pH, specific gravity, total dissolved solids, and conductivity.

   Inhibitor content is the concentration, in ppm, of residual corrosion inhibitor. The primary reason for measuring the inhibitor concentration in a water sample is to 1) ensure that it partitioned to the water phase (and not the hydrocarbon phase), and 2) ensure that it reached the end of a pipeline system and did not simply accumulate upstream. If residual measurements for other chemicals (e.g., biocides, etc.) are desired, contact an El Paso or chemical vendor's laboratory.

   The *pH* of a sample is the negative logarithm of the hydrogen ion concentration in an aqueous medium. The pH indicates whether an aqueous liquid sample is acidic, neutral, or alkaline. Neutral solutions have a pH of 7, alkaline solutions have a pH greater than 7, and acidic solutions have a pH less than 7.

   Specific gravity is the ratio of the density of the liquid being tested to the density of pure water at standard temperature. As more salts are dissolved in water, the specific gravity increases.

Total dissolved solids (TDS) are the sum of all dissolved ions (both cations and anions) detected in the analysis of an aqueous liquid. This value can also be used as a check to verify the completeness of an analysis since the sum of each of the individual constituents of the sample should approximate the value total dissolved solids value.

Conductivity is a measure of a substance to conduct electric current under an applied voltage. In a liquid, current is passed through the movement of ions. Conductivity tends to increase with the amount of TDS.

6. Sampling Frequency

1. In gas streams considered 'non-corrosive,' where liquids are present, sampling will be performed once per calendar year on a schedule set by the local supervision.

2. Depending on corrosion monitoring results or other considerations, Pipeline Services may issue a written notification designating a gas stream in a section of piping as corrosive. In the absence of other monitoring the location must be sampled twice per calendar year, but not to exceed 7½ months. However, Pipeline Services may recommend more frequent sampling.

3. If an upset condition is known to have occurred, a reasonable effort should be made to locate and obtain a liquid sample for analysis.

4. A liquid sample, when available, must be collected when a gas pipeline, vessel, meter tube, or tank is opened for maintenance, removal, or inspection.

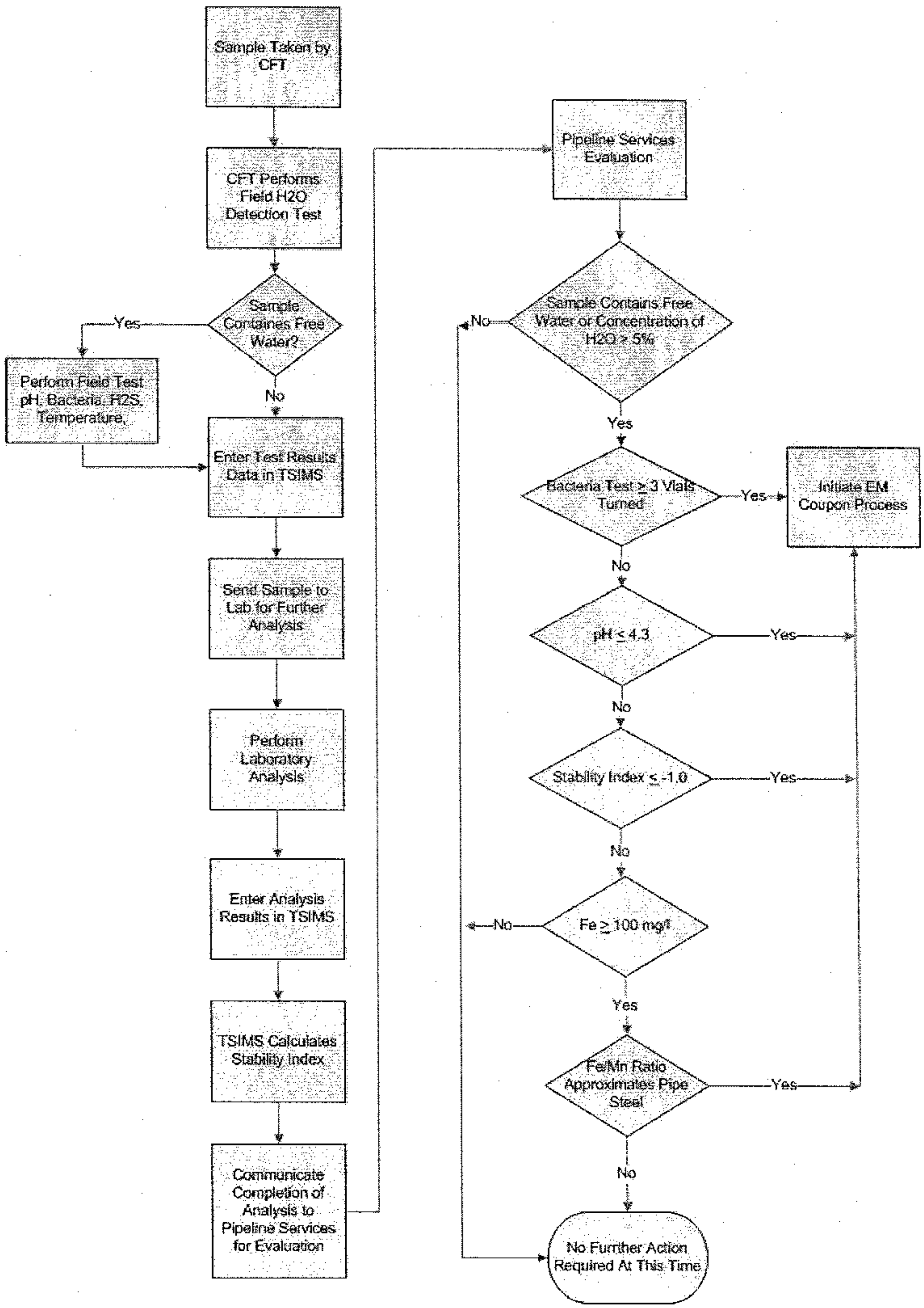
5. A liquid sample, when available, must be collected during pigging operations at pig receivers *unless Pipeline Services recommends less frequent sampling* (e.g., lines that are pigged once or more per week). When pig runs are made on internally coated lines, check the samples for evidence of coating debris. All sampling information should be reported on the appropriate Company form or database. If a sample is not taken, this must also be documented and a reason given.

Contact Pipeline Services to determine what tests need to be performed on liquid samples collected. Results of the sample analysis will be documented in the electronic database, or if not available, on the appropriate Company form and a copy sent to Pipeline Services.

§ 2 Liquids Samples: Internal Corrosion Evaluation

The following flow diagram illustrates the process used to evaluate liquids samples and the recommended actions resulting from this evaluation:

(continued next page)


Sample Taken by CFT
CFT Performs Field H2O Detection Test
Sample Containes Free Water?
Yes
Perform Field Test pH, Bacteria, H2S, Temperature,
No
Enter Test Results Data in TSIMS
Send Sample to Lab for Further Analysis
Perform Laboratory Analysis
Enter Analysis Results in TSIMS
TSIMS Calculates Stability Index
Communicate Completion of Analysis to Pipeline Services for Evaluation
Pipeline Services Evaluation
Sample Contains Free Water or Concentration of H2O ≥ 5%
No
Yes
Bacteria Test ≥ 3 Vials Turned
Yes
Initiate EM Coupon Process
No
pH ≤ 4.3
Yes
No
Stability Index ≤ -1.0
Yes
No
Fe ≥ 100 mg/l
No
Yes
Fe/Mn Ratio Approximates Pipe Steel
Yes
No
No Further Action Required At This Time

I. Securing the sample and performing field tests and documentation;

i. The qualified CFT secures a sample of liquids in accordance with Section 3 of the El Paso Internal Corrosion Field Guide.

ii. The qualified CFT performs a field H_2O detection test in accordance with Appendix A of the Internal Corrosion Field Guide.

iii. If the results of the field H_2O detection tests indicate the presence of free water, the qualified CFT performs additional field tests in accordance with Appendices A and B of the Internal Corrosion Field Guide to determine the pH, viable bacteria levels, dissolved H_2S concentration, total alkalinity and temperature of the water in the sample. If the result of the field H_2O detection test is negative for the presence of free water these tests are not performed.

iv. The CFT documents all information known in the field in the TSIMS database and ships the sample to one of El Paso's laboratories for further laboratory analysis.

II. Laboratory Analysis and Communication

i. Additional laboratory analyses are conducted in Accordance with Section 3 of the Internal Corrosion Guide.

ii. The results of all laboratory measurements are entered into the TSIMS database.

iii. If sufficient information is available, the TSIMS database calculates the Stability Index utilizing the information gathered during both the field and laboratory analyses.

iv. When all laboratory analyses are complete and data are entered into TSIMS, Pipeline Services is notified to perform an evaluation of the results of all field and laboratory tests to determine what, if any, actions should be taken.

III. Pipeline Services Evaluation and Recommendations

i. Pipeline Services reviews the data in TSIMS to determine what, if any, actions should be taken associated with information available from this sample.

1. If the field H_2O test does not indicate free water and the results of the laboratory tests do not indicate a concentration of water in the sample greater than 5% the sample is considered non-corrosive and no further action is indicated.

2. If the field H_2O test indicates free water or the results of laboratory tests indicate a concentration of a discernable water fraction in the sample (e.g., greater than 5% in transmission pipeline systems), the results of the field bacteria test are reviewed.

3. If the sample causes 3 or more media bottles to turn positive due to bacterial growth, a recommendation is made to initiate the EM coupon process and to perform further detailed investigations for the existence of internal corrosion.

4. If the sample causes less than 3 media bottles to turn positive further evaluation of the sample is warranted.

5. If the pH of the sample is less than or equal to 4.3, a recommendation is made to initiate the EM coupon process and to perform further detailed investigations for the existence of internal corrosion.

6. If the pH of the sample is greater than 4.3, further evaluation of the sample is warranted.

7. If the Stability Index calculated by TSIMS is less than or equal to -1.0 a recommendation is made to initiate the EM coupon process and to perform further detailed investigations for the existence of internal corrosion.

8. If the Stability Index calculated by TSIMS is greater than -1.0 or the Stability Index is unavailable, further evaluation of the sample is warranted.

9. If the laboratory analysis indicates a concentration of iron less than 100 mg/l no further action is warranted.

10. If the laboratory analysis indicates a concentration of iron greater than or equal to 100 mg/l, the ratio of the concentrations of iron to manganese is reviewed to determine if the ratio approximates the corrosion of pipeline steel. If this ratio does approximate the corrosion of pipeline steel, a recommendation is made

to initiate the EM coupon process and to perform further detailed investigations for the existence of internal corrosion.

11. If the ratio of iron to manganese in the sample does not approximate that of pipeline steel corrosion, no further action is warranted.

The information provided above is used as a part of our total integrity management program for the purpose of determining locations on the pipeline, which may need further investigation of the possible threat of internal corrosion to the pipeline.